"Subsurface Sensitivity Study of Geologic CO_2 Sequestration in Saline Formations"

Matthew Flett[1,2], Ian Taggart[1], Jason Lewis[1] and Randal Gurton[3]

[1] ChevronTexaco, Perth Australia , [2] Dept Petroleum Eng, Curtin Univ., Perth, Australia,
[3] ChevronTexaco EPTC, San Ramon, USA.

Paper prepared for 2nd Annual Conf. on Carbon Sequestration, Alexandria, VA May 5-8, 2003.

ABSTRACT

Similar to oil and gas developments, adequate subsurface characterisation of potential CO2 sequestration projects in deep saline formations has been limited by sparse and incomplete data sets. Most published studies to assess the performance of CO2 injection schemes are based on single models and do not adequately convey the impact of key uncertainties and possible outcomes, including compromised project objectives. A heterogeneous subsurface model of a high injection rate CO2 sequestration project was used as the base case. Sensitivities on geological, rock and fluid properties, particularly the rock/fluid interaction including gas-water relative permeability hysteresis were investigated. We focused on uncertainty sensitivities and interactions. Trapped gas saturations may be significantly higher than used in many previous sequestration studies. Significantly more volumes of trapped CO2 may occur due to this mechanism than has been previously considered.

1. INTRODUCTION

1.1 Background

The injection of Carbon Dioxide into geologic formations (CO2 sequestration) is being widely investigated as a means of reducing emissions to the atmosphere. In this paper we are focused on sequestration into saline formations. The term saline formations can apply to post-waterflooded oil reservoirs, water legs (downdip) of hydrocarbon formations, or relatively extensive or unconfined saline formations having no significant hydrocarbon trap, which are commonly known to soil scientists as aquifers. Our interest and our use of the term saline formations, in this paper are primarily directed towards the latter type of saline formation. Due to the more widespread occurrence of such large saline formations [Ref 1], these systems are considered likely potential candidates for future CO2 sequestration. The absence of demonstrably large hydrocarbon volumes means that over geologic time, generally considered of the order of millions of years, either hydrocarbon migration was absent or that some spill/leak occurred. Note that these large saline formations are not candidates for potable water or irrigation use. Previous discussions in the literature [Ref 1-3] have established that the success of long term CO2 sequestration in aquifers is dependent on long residence times and that CO2 differs from hydrocarbons by vastly increased solubility in water phases.

1.2 Past Work in CO2 Sequestration

The area of CO2 sequestration is an area of current activity with several actual and planned injection programs, laboratory studies of PVT and pore scale phenomena, as well as extensive numerical modelling efforts to forecast possible CO2 movement and trapping patterns. The extensive use of numerical methods is mandated given the complex forces and processes occurring over long time scales.

Current and proposed injection programs designed to improve the understanding of CO2 sequestration have been designed from the standpoint of static trapping, into a reservoir known to support a reasonable large hydrocarbon column, include:

- Sleipner Vest (offshore) Norway, Statoil and SACS consortium[Ref 4],
- Snovit [Ref 5]
- Weyburn Tertiary CO2 Injection Projec [Ref 6],
- Proposed GEOSEQ pilot [Ref 7] and
- In Salah BP/Sonatrach project [Ref 8].

Relatively few injection studies have considered assessing the dynamic trapping offered by relatively unconfined saline formations.

Laboratory studies currently focus on CO2–water solubility, relative permeability and reaction kinetics between fluid and rock phases. The literature on CO2 solubility is relatively mature, and has benefited from many years of study [Ref 9-10]. Many CO2 injection programs carried out to improve subsurface oil recovery [Ref 11]. The issue of accurate reaction kinetics between dissolved ions in the water and the rock fabric continues to be a complex one.

Due to the difficulty in correctly scaling laboratory measurements to reservoir conditions, simulation studies where computer models are used to forecast underground component, saturation and pressure changes are widely used. These models allow both a qualitative understanding of the interacting processes [Ref 12] but also provide predictions at the field scale level [Ref 13-15].

1.3 Key Issues for CO2 Injection in Saline Formations

Geologic CO2 sequestration shares many of the same factors that contribute to large uncertainties in predicting rates of subsurface hydrocarbon flows in the oil and gas industry. These uncertainties are a direct result of the difficulty in characterising subsurface formations in terms of the magnitude and spatial variability (heterogeneity) porosity and permeability. Additionally many issues relating to multiphase fluid behaviour at higher temperatures and pressures are important given the relatively low viscosity (high mobility) of the CO2 relative to brine. Frequently, our understanding of geologic formations is based on limited and isolated information obtained from a few wells. Sampling rates of less than 1 in 10^9 are common. Precise knowledge of effective subsurface volumes of hydrocarbons and aquifer volumes, in the absence of long term production data, can be surprisingly low. For these reasons, CO2 sequestration studies are subject to the same large outcome uncertainties that confront the upstream oil and gas industries. CO2 injection programs into saline systems need to account for multiphase flow involving a CO2 rich phase and brine. For reservoirs deeper than 800 metres, the CO2 phase tends to be supercritical exhibiting liquid like densities but still possessing gas-like viscosity. Flow in the reservoir while injection occurs involves a mix of gravity and viscous forces. After injection ceases, any subsequent movement with time tends to be dominated by gravity and capillary forces. As we will show later, the injection phase tends to be drainage dominated, while the migration phase tends to be imbibition dominated.

Current activity in geologic sequestration of CO2 can be described as follows:

a) CO2 phase studies. EOS modelling particularly taking into account small impurities.
b) Multiphase relative permeability modelling & wettability studies specific to CO2 systems
c) Hysteresis and Gas Trapping Phenomena
d) Brine-Rock Reactivity
e) Resolving disparate process time and spatial scales
f) Numerical issues. Similar to the oil and gas industry, the numerical formulation of sequestration problems can be treated on a mole by mole basis using compositional models, which are frequently approximated by so-called Black Oil models which assume in-situ properties vary according to pressure alone.
g) Sensitivity issues. Because CO2 sequestration projects are few, and oil field experience provides ample examples where actual performance failed to meet expectations, it is important to understand the likely impact of uncertain parameters and operating practices.
h) History matching actual pilots (recognising movement of injected gas frequently results in overestimated gas injected programs in the oil and gas industry)

1.4 Objectives.

The work in this paper seeks to address only a small subset of the key issues noted above. We are particularly interested in identifying those parameters likely to be important when sequestering CO2 in saline formations. Widespread use is made of reservoir simulation to model the injection process and subsequent migration of CO2 rich phases. Few of these studies include brine-rock reaction kinetics due to and absence of reliable rate data, and often disparate project (ie injection) time scales compared to the time scale required to sequester CO2 by mineral trapping [Ref 2,12].

Few studies, however, have presented the results of changes in key inputs or sensitivities, to model results. Risk and uncertainty management is a key component of the current day hydrocarbon industry and a risk assessment, which involves an assessment of the chance of undesirable outcomes, is a normal part of project development. In this regard reservoir simulations provide a useful tool to identify and rank key project risks.

Related to the issue of risk identification is the establishment of signposts or yardsticks to monitor an actual injection program, or to quantify and rank the results of sensitivity studies. One widely quoted yardstick is the 2% pore volume screening criteria developed by Van Der Meer [Ref 3]

One major objective of this work is borrow results from the petroleum industry concerning the potential impact of hysteresis in relative permeability data, particularly for the CO2 rich phase [Ref 17,18]. The underlying origins for relative permeability hysteresis are the phase trapping of the displaced phase during imbibition and changes in contact angle that occur between two immiscible phases and the rock. When the wetting phase is receding the term drainage applies. Similarly or advancing wetting phase is referred to as imbibition. Several articles have dealt with the issue of relative permeability hysteresis in the context of CO2 flooding where alternate slugs of CO2 and water are injected into oil bearing formations. Such cycles of CO2 and water result in several drainage and imbibition cycles respectively.

The rest of this paper is organised as follows: We first summarise a heterogeneous reservoir simulation model that provides the base case for a series of sensitivities that follow. The sensitivities are by no means exhaustive, but enable a suitably wide variation in parameters to be studied and there interactions assessed. We introduce the Land trapping formulation of gas trapping that is frequently employed in the petroleum literature to account for the high efficiency of gravity stable gas floods on the one hand, and the relatively poor gas recovery experienced by gas reservoirs with aquifer or injected water drive. These tow processes represent drainage and imbibition processes respectively.

2. COMPUTER MODELING OF CO2 INJECTION

In order to assess the impact on changes to parameter values, we employed a heterogeneous subsurface model which displayed many features of candidate reservoirs that we are studying. Table 1 summarizes salient features of the base simulation model employed here.

2.1 Description of expected CO2 Movement

In the cases considered here CO2 will be injected at reasonable high rates into a downdip location. While injection continues some of the CO2 will dissolve outright, however the majority will coalesce into a CO2 rich phase and move away from the wellbore under viscous and gravity forces. Depending on the ratio of these forces the CO2 will form a vertical plume or will extend some distance away in a horizontal direction. In the setting described here, the vertical permeability is relatively weak.

2.2 Static Model

The example we will briefly describe originated from marine turbidite depositional environment. The sediments in turbidite systems are deposited in deep water and are known to provide long horizontal continuity and relatively little vertical permeability. The model is based on a saline formation which is truncated by a fault at the crest of the structure. Assuming no solubility, lighter immiscible fluid injected downdip will tend to migrate upwards and will, at some time, reach the crest some 20 km away. In our model, the fault provides a possible leak point in some cases.

The key issue here is that we seek long-term sequestration of CO2 in a dynamic sense [Ref 3].

Figure 1 and 2 display perspective views of the grid showing permeability and porosity fields. The structure dips slowly upwards from the 3-well injection site. A fault is located at the crest of the model.

2.3 Dynamic Model

We employ ChevronTexaco's CHEARS[R] reservoir simulation package to represent the CO2 water system in a black oil formulation. Temperature is held constant while phase properties, such as viscosity are assumed to be functions of Pressure. Our simulations employ a CO2 injection rate of 120 mmscfd distributed equally amongst 3 injector wells located downdip some 20 km from the crest. Injection occurs into layers 11 through 13, (in a 14 layer model) in all wells. Injection proceeds for a period of 30 years whereupon injection totally ceases but monitoring would continue.

For the cases where the fault is assumed to leak, pseudo production wells with high PI's were assigned to cells immediately adjacent to the fault location. Whenever static pressure rose above initial pressure levels fluid therefore was able to leave the system, thereby simulating fluid exiting through a fault.

The grid design and spacing employed in the model ensured that higher spatial resolution occurred around the injection sites and likely migration paths (ie towards the top of the reservoir). We recognise that simulated gas injection performance is often dependent on grid dimensions. Simulated solubility effects are known to be initially enhanced as grid cells are coarsened due the (usual) assumption of instantaneous equilibrium. Grid size effects were not examined in this initial work and will be studied subsequently.

2.4 Relative Permeability Model and Gas Trapping

The gas liquid relative permeability curves used in this study were based on oilfield reservoir simulation experience. The authors attempted to capture a range of relative permeability relationships to study their impact, rather than relying on a hypothetical reference case. During CO2 injection, the water saturation in the formation near the injectors decreases as the CO2 saturation increases, and thus the rock-fluid system is in a drainage state. When gas injection stops, or as the gas plume rises due to density differences, the water saturation may increase again causing an imbibition state. It is during imbibition process that gas trapping can occur.

Drainage relative permeability curves can be estimated by the well known Brooks-Corey [Ref 18] equations for a two phase system.

$$k_{rw} = (S_w^{\,*})^{\frac{2+3\lambda}{\lambda}}$$

$$k_{rg} = (1-S_w^*)^2 (1-(S_w^*)^{\frac{2+\lambda}{\lambda}})$$

The superscript (*) refers to normalized saturations; that is saturation space that does not contain irreducible water.

$$S_w^* = \frac{S_w - S_{wir}}{1 - S_{wir}}$$

$$S_g^* = \frac{S_g}{1 - S_{wir}}$$

The λ parameter is the pore size distribution index, and typically ranges from 0.5 for a wide range of pore sizes to 5 for a uniform pore size rock. These equations can be easily rewritten in terms for Sg*, since

$$S_g^* + S_w^* = 1$$

Land [Ref 17] found the following simple relationship between the trapped gas saturation and the initial gas saturation (prior to the imbibition cycle).

$$C = \frac{1}{S_{gt}^*} - \frac{1}{S_{gi}^*}$$

C is the trapping constant. Assuming a nominal formation porosity of 0.25, trapped gas saturations vary from 0.20 to 0.40 based on practical oilfield studies [Ref 19,20]. Thus Lands constant is typically in the range of 1 to 3.

Following Land's work, a modified Brooks-Corey equation can be used for gas phase hysteresis. Once Sgt* is defined, the free gas saturation Sgf* can be used to calculate imbibition gas relative permeability.

$$S_g^* = S_{gt}^* + S_{gf}^*$$

The complete gas imbibition equations are not presented here, but this approach is implemented in the CHEARS reservoir simulator [16] and was used for this study.

3. SENSITIVITY STUDIES

A key objective of this study was to understand parameters that impact the displacement of CO2 in saline formations. That is, the focus was centred on reservoir engineering variables rather than the static reservoir description. The strategy was to use a wide range of displacement-related parameters and to determine the parameter effects, rather than attempting to quantify displacement performance using hypothetical midpoint parameters.

The key parameters varied in this screening study were:

- CO2 solubility in brine
- Drainage relative permeability curves
- Gas relative permeability hysteresis using:
  - pore size distribution parameter
  - Land's trapping constant
- Crestal fault leak/seal
- Saline formation volume

Table 1 summarizes these parameters in a strategy table. Table 2 summarizes the simulation model parameters and ranges used. The authors acknowledge that there are many other model parameters and model formulation issues that will impact simulated injection performance. Some of these parameter/issues are:

- Grid size effects
- Injection strategies
- Physical properties of the fluids
- Physics of diffusion and convection
- Geologic model description
- Explicit variation of the permeability field, horizontally and vertically (note that changes in permeability are implied through changes the trapping constant)
- Petrophysical cutoffs and the quantification of non-reservoir material and pore space

These issues will be addressed in ongoing studies, and will ultimately provide a more comprehensive framework for the prediction of CO2 injection in saline formations.

In oilfield reservoir simulation studies, it is conventional to conduct a one-variable-at-a-time sensitivity analysis of low and high parameter values. Simulation results are then often plotted in a so-called tornado diagram. In this study, parameters were also varied in combinations to investigate a wider range of flood performance. These parameter interaction effects are significant indeed and will be presented in the next section.

Simultaneous variation of parameters can be managed in a statistically rigorous way using Design of Experiments (ED) methodology. ED methods have recently been applied to numerical experiments and reservoir simulation [Ref 21]. ED techniques can be used to minimize the number of experiments and to obtain the statistical ignorance of a parameter's effect. Again ED will be used in ongoing studies.

4. YARDSTICKS and METRICS

There is a need to be able to determine the definition of success for a CO2 sequestration project, to examine the effectiveness of a certain sequestration strategy to limit the release of CO2 to the atmosphere.

There are limited current yardsticks set to be able to measure the progress of a sequestration project, unlike oil and gas developments which can use production data metrics to measure the outcome of a development. Thus some benchmark metric measurements have been determined that seek to identify areas of uncertainty associated subsurface CO2 sequestration.

4.1 Proposed Metrics

Proposed metrics for measuring sensitivity of a sequestration project to risk are estimated at different project times, via:

- the distance of injected CO2 away from the injected location,
- the volume of free CO2 that exists in the reservoir in the CO2 rich phase (ie has not dissolved into formation waters),
- the size of the plume of CO2 migrating up dip, and
- the pressure change associated with the CO2 injection at the crestal fault location.

These four measurements will provide insight into the success of a proposed project during injection time. The migration distance of CO2 is key measure to show the probability of a plume reaching a leak point in the form of a non-sealing fault. The volume of free gas in the reservoir represents the amount of CO2 not trapped by dissolution trapping and hence the amount of gas that remains as a potential leakage risk. The size of migration plume is key measure of the success of gas trapping as permanent trapping mechanism and the risk associated with a volume of gas migrating to a leak point. The pressure change at the fault, relative to the base case model, gives a representation of the sensitivities associated with a pressure sensitive seal at a fault and potential risk of leakage through the fault to surface.

5. RESULTS and OBSERVATIONS

Visualization of gas saturations in the model at 8000 years post injection for different sensitivities are shown in Figures 5 to 10. An image of the injection layer and the top layer of the modeled formation for the base, very high gas trapping and very low gas trapping cases at the specified time are shown. For the base case, Figures 5 & 6, a gas plume forms. Eventually the plume reaches the top layers and forms a gravity tongue. The gravity tongue continues to migrate up dip. During this sequence of events, a significant amount of CO2 remains trapped about the injection wellbores once injection ceases and imbibition mechanisms dominate. For the very low gas trapping case, Figures 7 & 8, gas trapped about the injector location is smaller than the base case and the size of the migrating plume and distance covered by the plume is greater. Figures 9 & 10, representing the very high gas trapping case show that gas remains trapped about the wellbore and that no migrating gas plume/tongue has developed.

5.1 Volume of Free CO2

Simple variation of tested sensitivities on the volume of free gas is shown in Figure 11, at the timing of the end of injection and the end of the 8000 years. Formation size, solubility and gas trapping have an effect on the amount of gas that is dissolved into formation waters. The larger formation has enhanced solubility characteristics over the base and smaller formation sizes as each cell in the model as more pore water to contact the gas and dissolve it. The solubility option obviously effects if gas in dissolve into the water. High gas trapping cases with gas trapped about the wellbore have limited contact between with gas and unsaturated formation water, unlike low gas trapping cases where gas migrates, migrating gas contacts unsaturated water and dissolves into formation waters. The volumes for all cases run is shown in Figure 17. The results show that model with increased gas mobility, a less heterogeneous formation and very low gas trapping can lead to large amounts of free gas remaining in the reservoir compared to the simple variations shown in Figure 11. Negative simple variable variations in terms of gas dissolving into the formation can lead to cascading cumulative effect.

5.2 Pressure change at Fault

The difference in pressure in the formation relative to the base case, measured at the proposed fault location is shown in Figure 12. Full set of results are shown in Figure 18. All models with a non-sealing fault have a significantly lower pressure at fault at both the 30 and 8000 year points. A smaller formation can lead to significant increase in pressure at fault due to smaller amount of pore space available. Fresher water in the formation can lead higher pressure at the fault and larger formation space leads to a drop in pressure. Other sensitivities are not so significant in size compared to the base case.

5.3 Movement of Injected CO2

The migration distance of injected CO2 is shown for simple variation in Figure 13 for 30 and 8000 years. The full spectrum of results is shown in Figure 15. The key variable in the simple variation analysis is the amount of gas trapping, following with formation size. Low gas trapping and small formation size increases the migration distance of the gas, high gas trapping and larger formation size limits the extent of gas migration. In the combined sensitivities cases, the combined effect of increased gas mobility, low gas trapping and less heterogeneous rock ("worst" case) lead to large distances being covered, even reaching the fault in some cases. The cases with decreased gas relative permeability, more heterogeneous rock and high gas trapping had very limited gas migration distances.

5.4 Plume Volume

The volume of the migrating CO2 plume has a strong relation to migration distance travelled by the plume, the larger the plume, the further the plume travelled up dip. This is shown in Figure 14 for simple parameter variation and Figure 16 for all cases considered. Gas trapping, and relative permeability affects the size of the plume. Increased gas mobility and decreased gas trapping leads to large plume volumes and vice versa.

6. INSIGHTS

Based on the result contained in this work we have drawn three major conclusions:

1) We have developed and applied useful metrics for assessing injection performance.
2) Demonstrated that gas trapping, due to relative permeability hysteresis, has a large effect on the volumes of mobile CO2 at both the end of injection 30 years and subsequently at 8,000 years.
3) Shown that considerable interactions exists between sensitivity parameters,

This work has proposed the use of several metrics to assess and compare the performance of injected CO2 into saline formations. It is difficult to judge the performance of a given case on the basis of one metric alone. This point is emphasised by some of the more riskier outcomes, where CO2 rapidly moves away from the injection site in an updip direction. We note that previously published screening criteria, such as that proposed by Van der Meer [Ref 2] which ratios the injected CO2 volume to total pore volume available, do not differentiate such cases.

The importance of relative permeability hysteresis which leads to gas trapping is one area that has not received must attention in a CO2 sequestration context. The origin of high values of trapped gas saturation result from contact angle and fluid interface hysteresis at the pore scale level. The petroleum industry has adopted use

Further work needs to be performed to assess the impact of other parameters. In this initial study the kv/kh ratio has not been varied significantly nor has the effect of possible dip changes in the reservoir been considered. We consider these as two potentially important variables. Future studies are also aimed at varying the stratigraphy (stratigraphic layering) so that, for example, layering styles conformable to the top can also be assessed.

7. NOMENCLATURE

C = trapping constant
Sw = water saturation
Swir = irreducible water saturation
Sw* = normalized water saturation
Sg = gas saturation
Sg* = normalized gas saturation
Sgt* = normalized trapped gas saturation
Sgi* = normalized initial gas saturation
Sgf* = normalized free gas saturation
λ = pore size distribution index

8. REFERENCES

1. Cook PJ, Rigg, A and Bradshaw, J: Putting it back where it came from: Is Geological Disposal of Carbon Dioxide an option fro Australia. APPEA J. 2001.
2. Van der Meer, LGH, CO2 Storage in the Subsurface. GHGT6, Kyoto (2002)
3. Lindeberg, E: Escape of CO2 from Aquifers. Energy Convers. Mngt 1997; 38. S235-240.
4. Korbol R, Kaddour A. Sleipner Vest CO2 disposal-injection of removed Co2 into the Utsira formation. Energy Convers. Mngt 1995; 36. 509-512.
5. Snovit LNG and CO2 reinjection: See http://www.co2sequestration.info/
6. Weyburn EOR Project. See http://www.ptrc.ca/projects/weyburn.htm
7. Hovorka SD and Knox PR, Frio Brine Sequestration Project in the Texas Gulf Coast. GHG6: Sixth International Conference on Greenhouse Gas Control Technologies, Kyoto, Japan, October 2002 See also. http://www.beg.utexas.edu/environqlty/co2seq/fieldexperiment.htm
8. Riddiford FA, Tourqui, A, Bishop , CD. Taylor, B , Smith, M., A Cleaner Development: The In Salah Gas Pproject, Algeria, GHGT6, Kyoto (2002)
9. Enick, RM and Klara, SM, CO2 Solubility in water and Brine under reservoir conditions. Chem. Eng. Comm. 1990, 90, pp 23-33.
10. Chang, Y, Coats, BK, Nolen, JS; A Compositional Model for CO2 Floods Including CO2 Solubility in Water. SPERE, April 1998, 155
11. Blunt M., Fayers FJ, and Orr, FM. Carbon Dioxide in Enhanced Oil Recovery. Energy Convers Mgmt 1993;34:1197-1204.
12. Preuss, K, Xu T, Apps, J, Garcia, J; Numerical Modeling of Aquifer Disposal of CO2. SPE 66537, presented at Prod. Env. Conf. San Anonio Tx, 26-28 Feb. 2001
13. Preuss,K Tsang, C, Law DH and Oldenburg, CM. An Intercomparison Study of Simulation Models for Geologic Sequestration of CO2. GHGT6, Kyoto (2002)
14. Van der Meer, LGH, Atrs, RJ and Paterson, L; Prediction of Migration of CO2 after injection into a Saline Aquifer: Reservoir History Matching of a 4D Seismic Image with a Compositional GAS/WATER model.. GHGC5, Cairns 2001)
15. Ennis-King J and Lincoln Patterson L: Engineering Aspects of Geological Sequestration of Carbon Dioxide. SPE 77809, presented at Asia Pac. Oil & Gas Conf, Melbourne, Aust. Oct 8-10, 2002.
16. CHEARS[R] (ChevronTexaco Hydrocarbon Extended Application Reservoir Simulator). Engineering and Mathematics Manual. Proprietary 1997.
17. Land, CS : Calculation of Imbibition Relative Permeability for Two and Three Phase Flow from Rock Properties, Trans AIME 1971, pp. 149.
18. Brooks RH and Corey AT : Properties of Porous Media Affecting Fluid Flow, Journal Irrigation and Drainage Engineering, 1966.

19. Skauge A, Veland I, Larsen JA; Factors Influencing Three Phase Flow Parameters in WAG Experiments. SCA-9932
20. J.G. Kralik, L.J. Manak, A.P. Spence, and G.R. Jerauld, Trapped Gas, Relative Permeability and Residual Oil Saturation of an Oil-Wet Sandstone1 SCA 2011.
21. Friedmann F, Chawathe A, and Larue D.: Uncertainty Assessment of Reservoir Performance using Experimental Designs, CIM 2001-170, presented at 2001 Canadian International Petroleum Conference. CO2 Wag studies – J. Kamath, S.B Gorell, MK Roper (with G. Pope),

TABLE 1: Sensitivity Strategy Table

Aquifer Size	**Solubility**	**Relative Permeability**	**Hysteresis**		**Fault Behavior**
			Trapping Constant	**Pore Size Variation**	
Base	On	Base	Base	Base	Seal
Large	Off	Low Gas Mobility	Very High	More	Non-sealing
Small		High Gas Mobility	High	Less	
			Low		
			Very Low		

TABLE 2: Model Description Summary

Depositional Setting	Marine
Typical horizontal permeability	50 mD
Typical vertical permeability	0.01 mD
Typical porosity level	0.20
Salinity (NaCl) (controls solubility)	70000 ppm
Rate of injection	120 MMscf/d
Solubility (scf/bbl)	~125 scf/bbl at initial conditions using Ref [10] low range was no solubility high was that equiv. to 7000 ppm
Number of injection wells	3
Injection time	30 years
Monitoring/Run time	8000 years
Depth	~ 7000 ft tvd
Average Initial Pressure	~ 3100 psia
Typical injection grid block size	820 ft by 1000 ft by 250 ft
Typical top layer grid block size	820 ft by 1000 ft by 25 ft
Model dimensions	27 by 50 by 14
Pore Volume	975 B. rb (low *0.67, high *1.33)
Relative permeability drainage exponent**, N_g, N_w	2, 5 Low gas mobility 3,3 High gas mobility 1.5, 6.5
Gas relative permeability hysteresis parameters Lands trapping constant, C Pore size distribution index, λ	 Range 0.6 to 4; base 1.7 Range 0.5 to 5; base 2

** Note CHEARS uses an internal formulation for gas hysteresis, and the drainage curves that were used can be closely represented by these Corey exponents

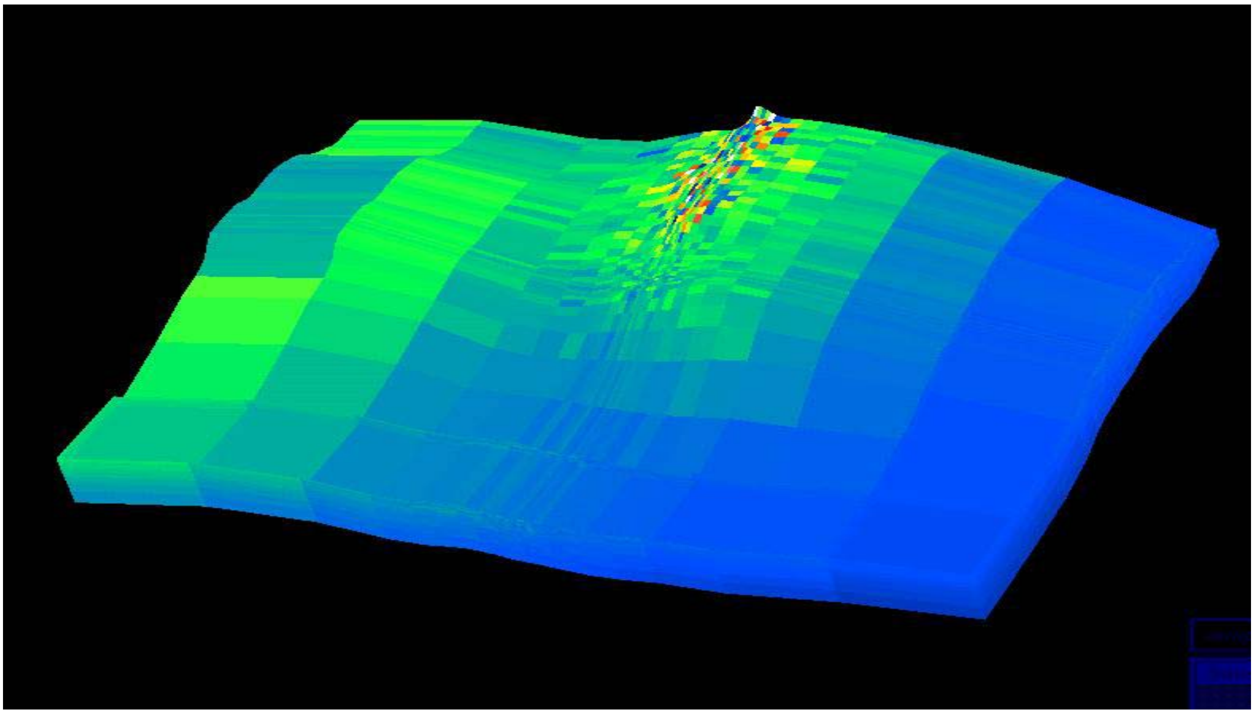

Figure 1: Porosity display of simulation model

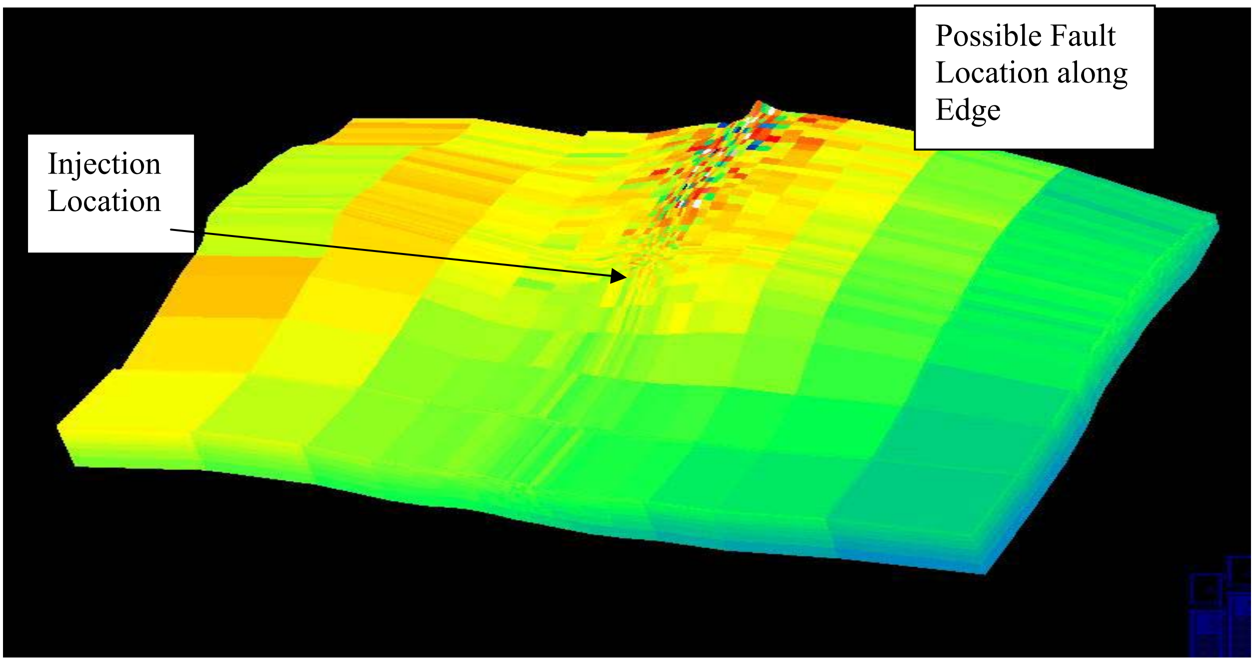

Figure 2: Horizontal permeability display of simulation model showing location of Injectors and fault location along the updip edge of the model grid.

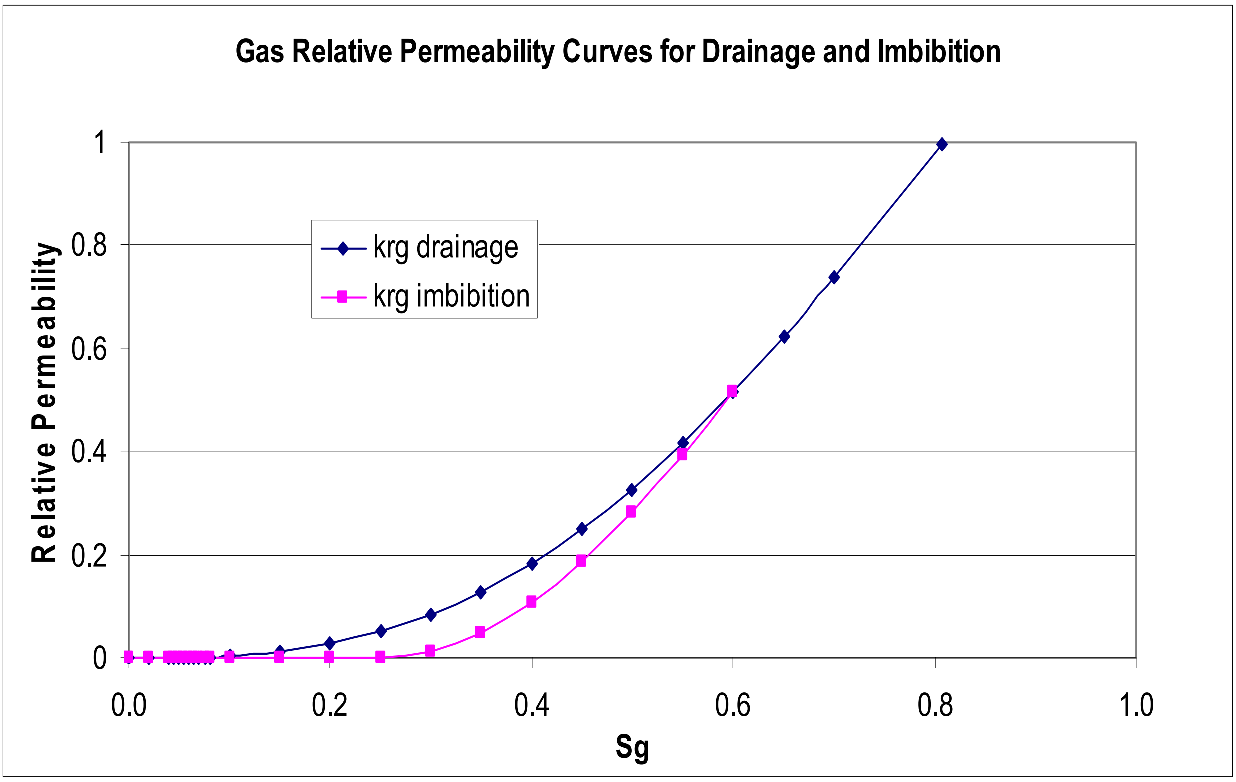

Figure 3: Gas relative permeability curves for drainage and imbibition cycles

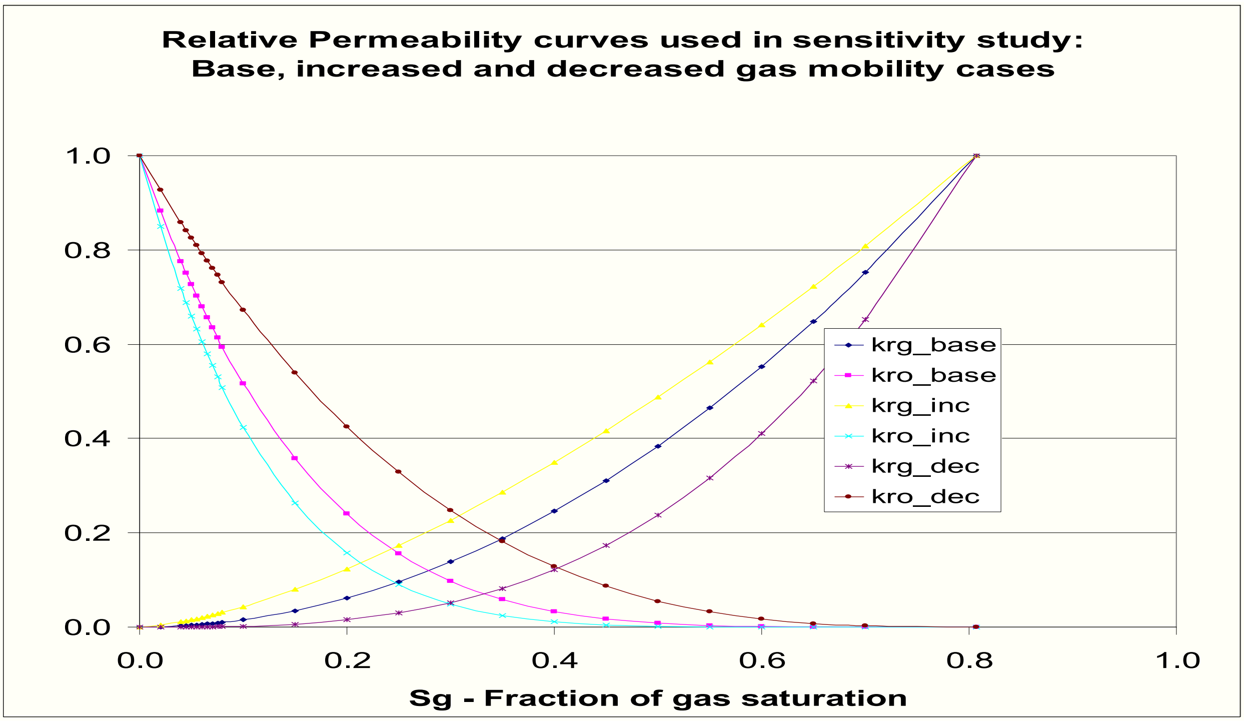

Figure 4: Corey equation derived relative permeability curves used for this study

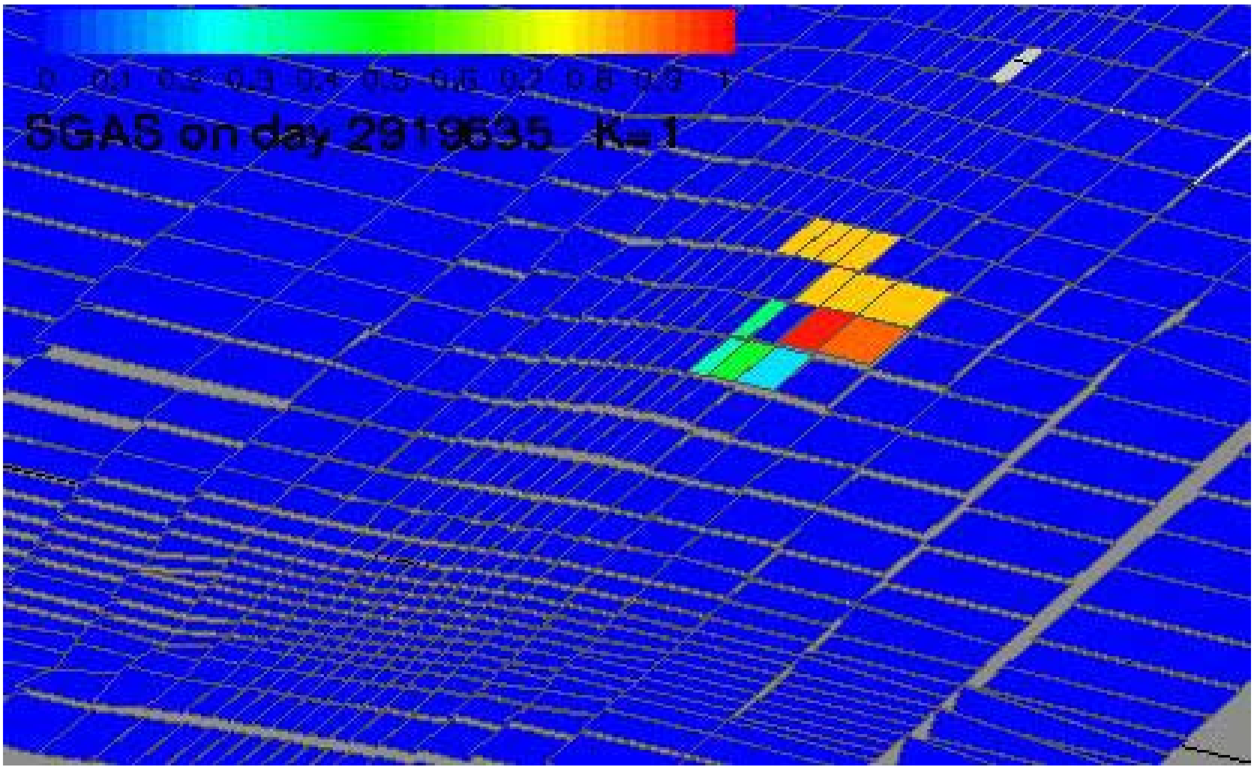

Figure 5: Simulation visualization at 8000 years, Top layer, Base case.

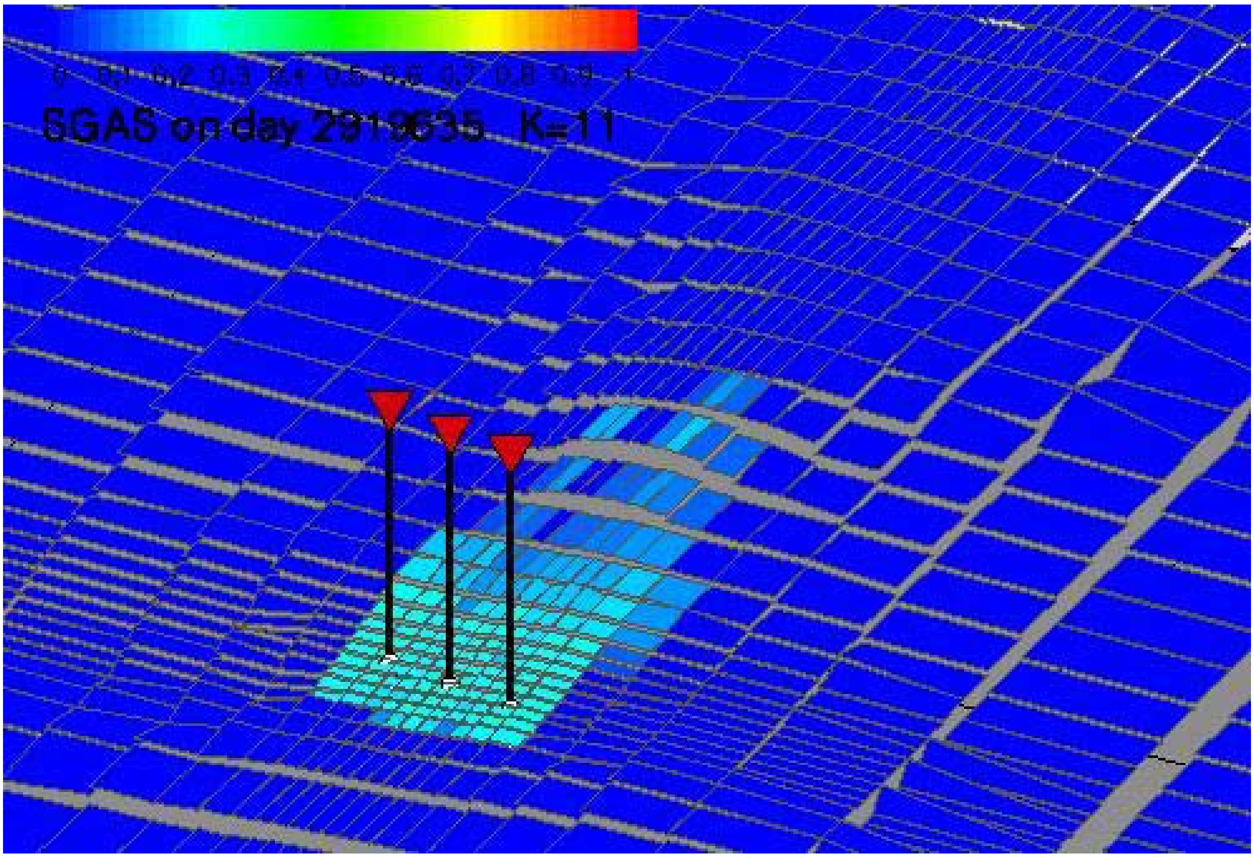

Figure 6: Simulation visualization at 8000 years, Injection layer, Base case.

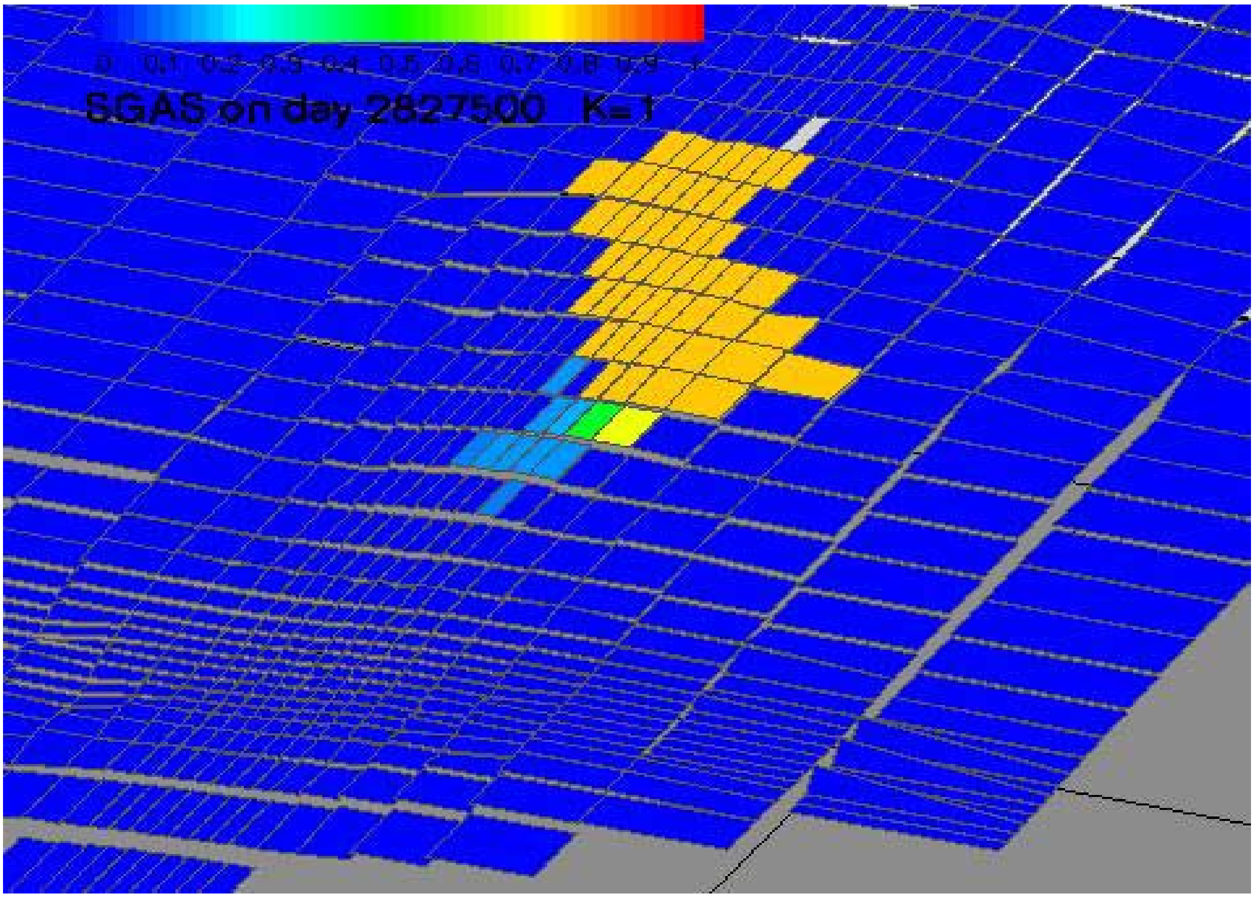

Figure 7: Simulation visualization at 8000 years, Top layer, Very low gas trapping case.

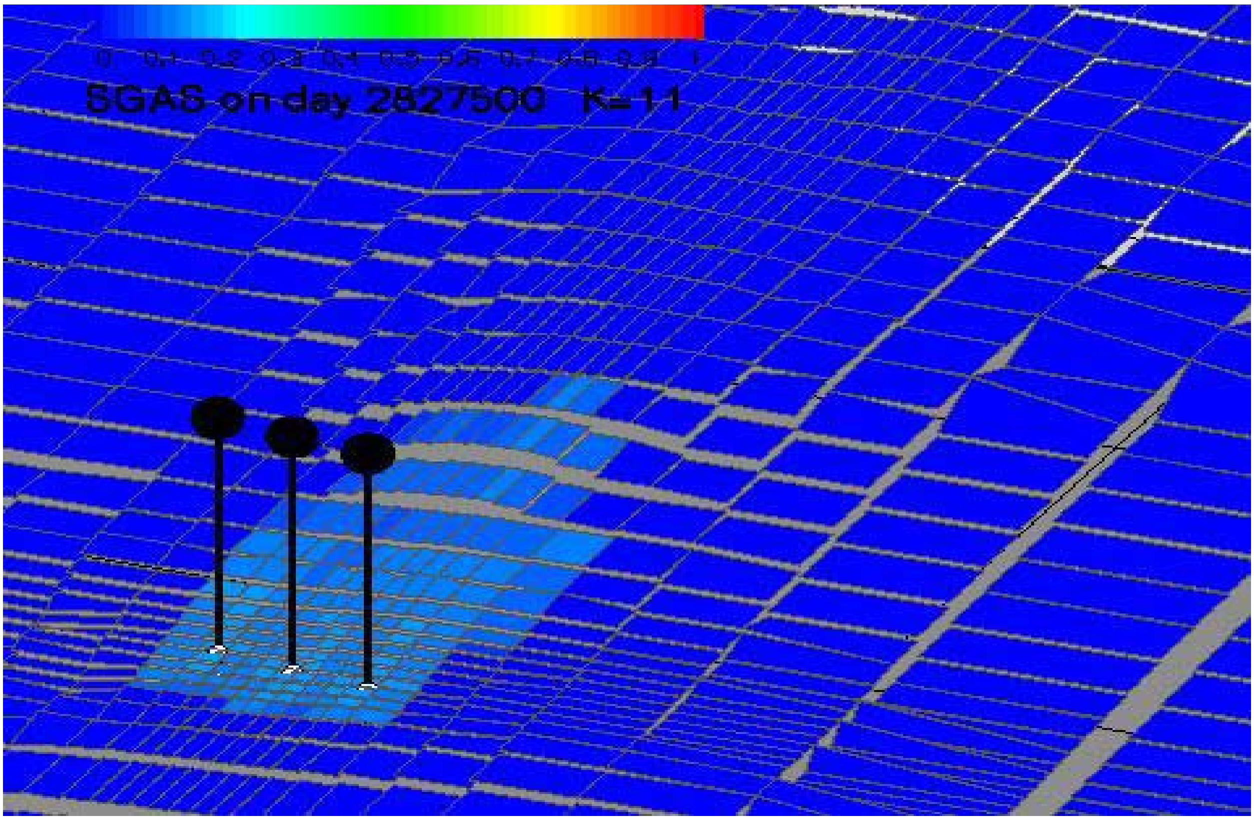

Figure 8: Simulation visualization at 8000 years, Injection layer, Very low gas trapping case.

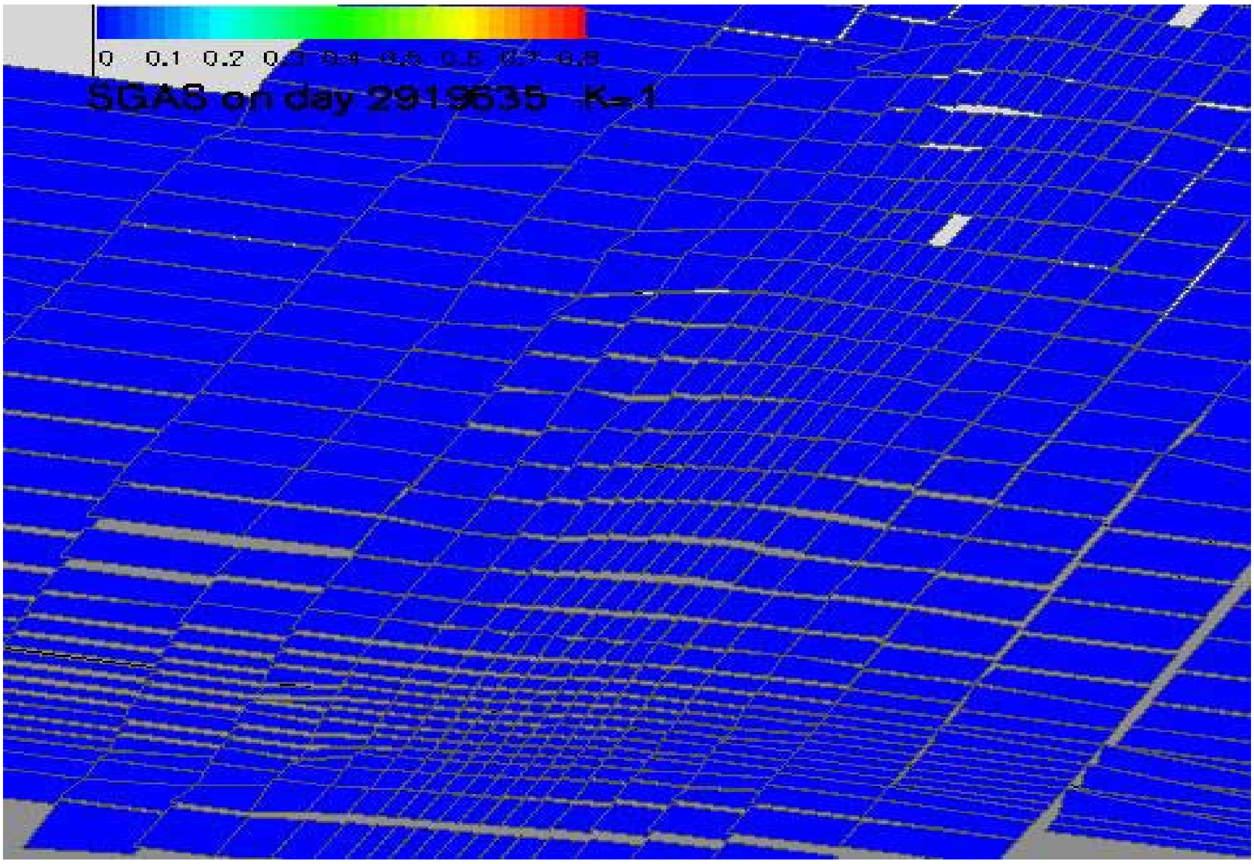

Figure 9: Simulation visualization at 8000 years, Top layer, Very high gas trapping case.

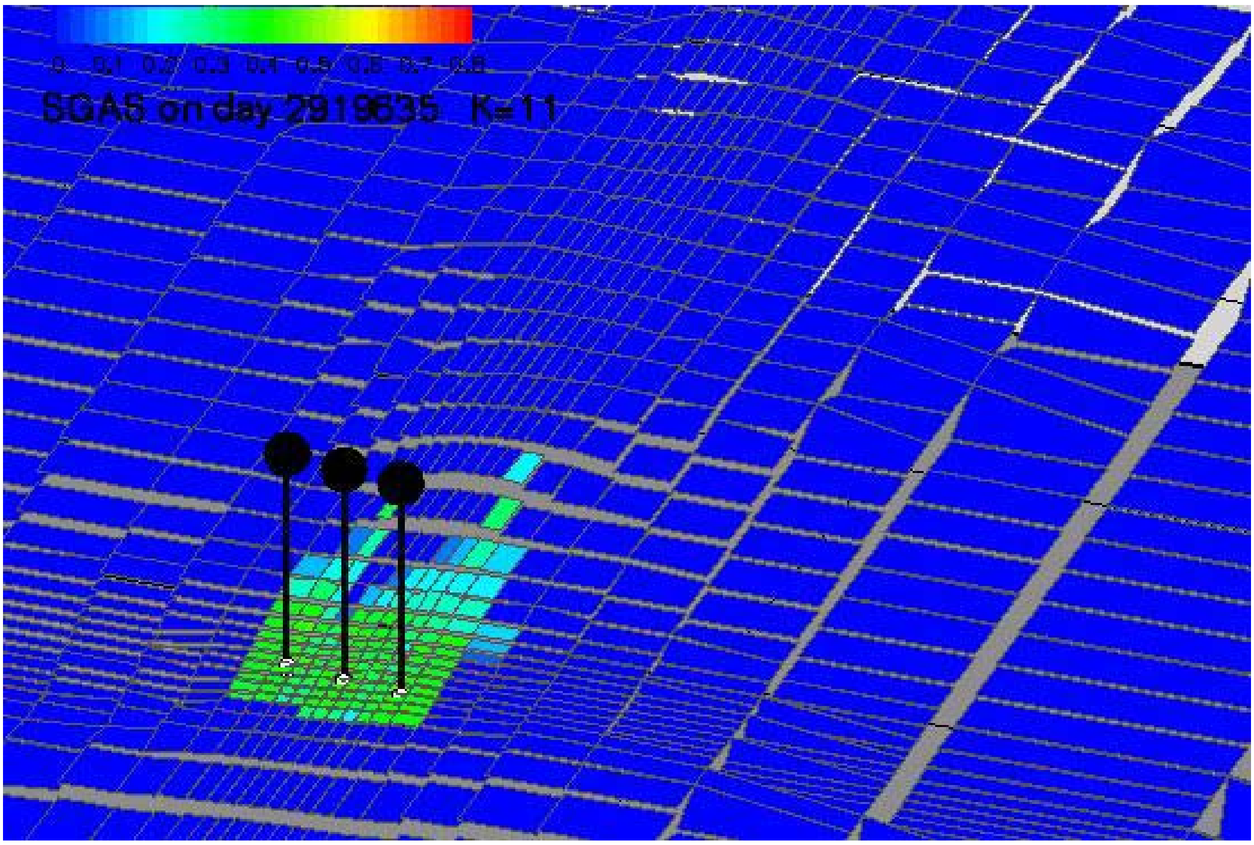

Figure 10: Simulation visualization at 8000 years, Injection layer, Very high gas trapping case.

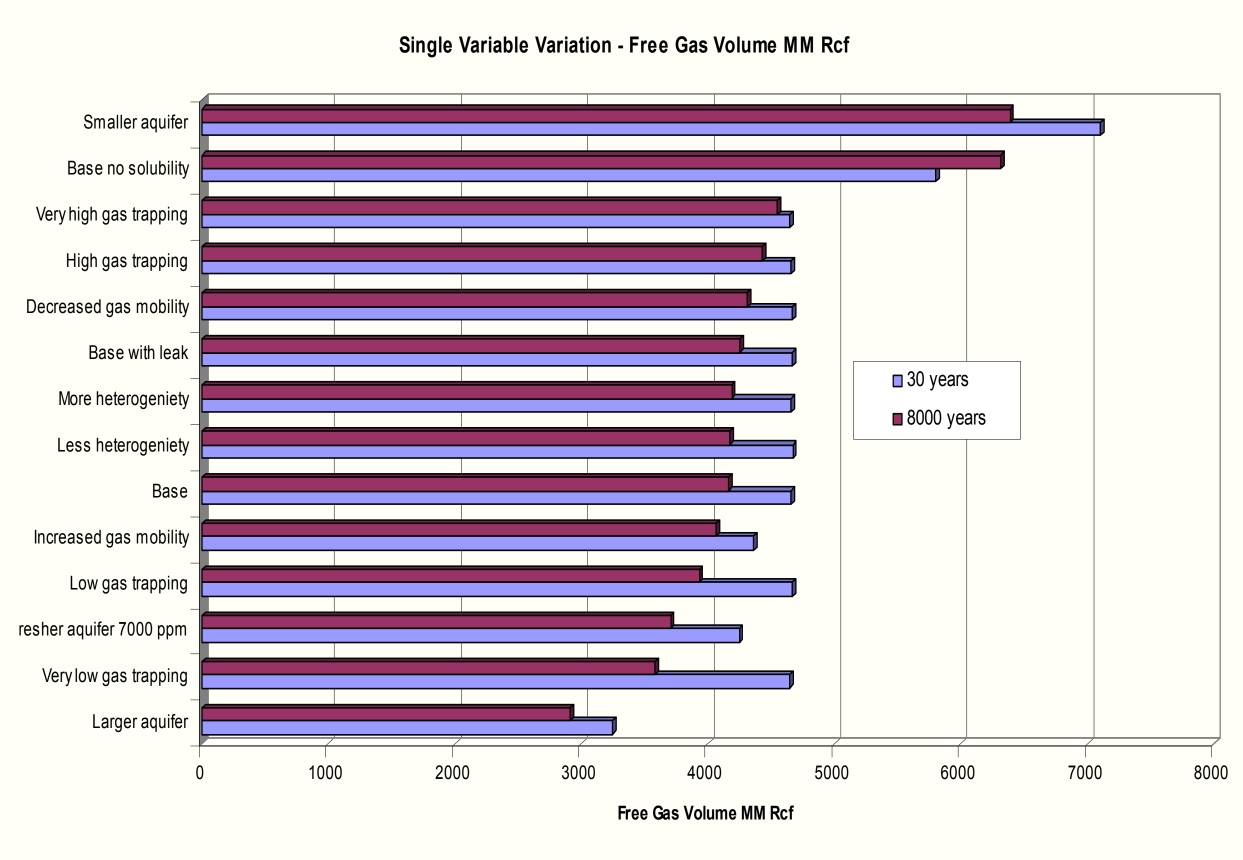

Figure 11: Simple variation of parameters; Free gas volume after 30 & 8000 years.

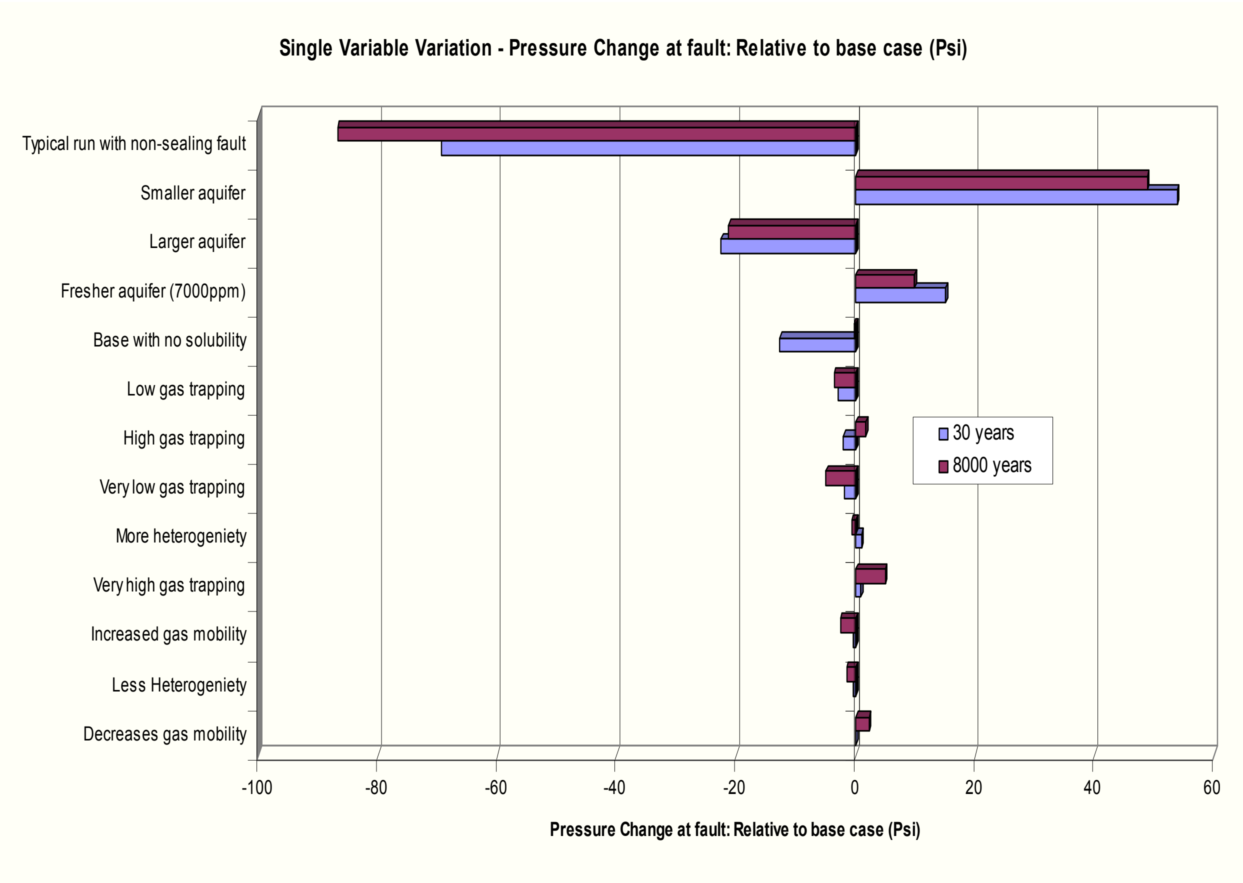

Figure 12: Simple variation; Pressure change at fault, relative to base case after 30 & 8000 years

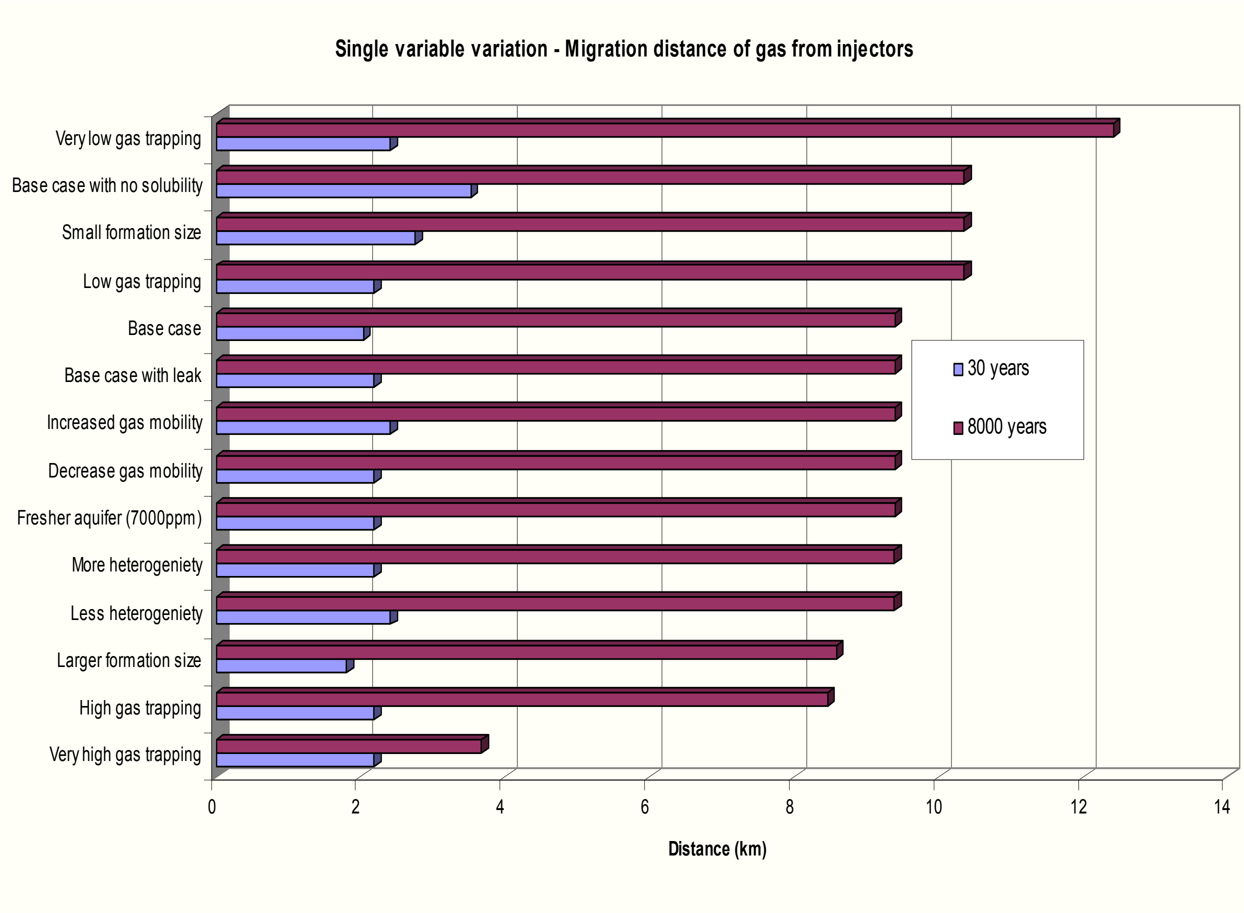

Figure 13: Simple variation; Migration distance from gas injectors at 30 & 8000 years

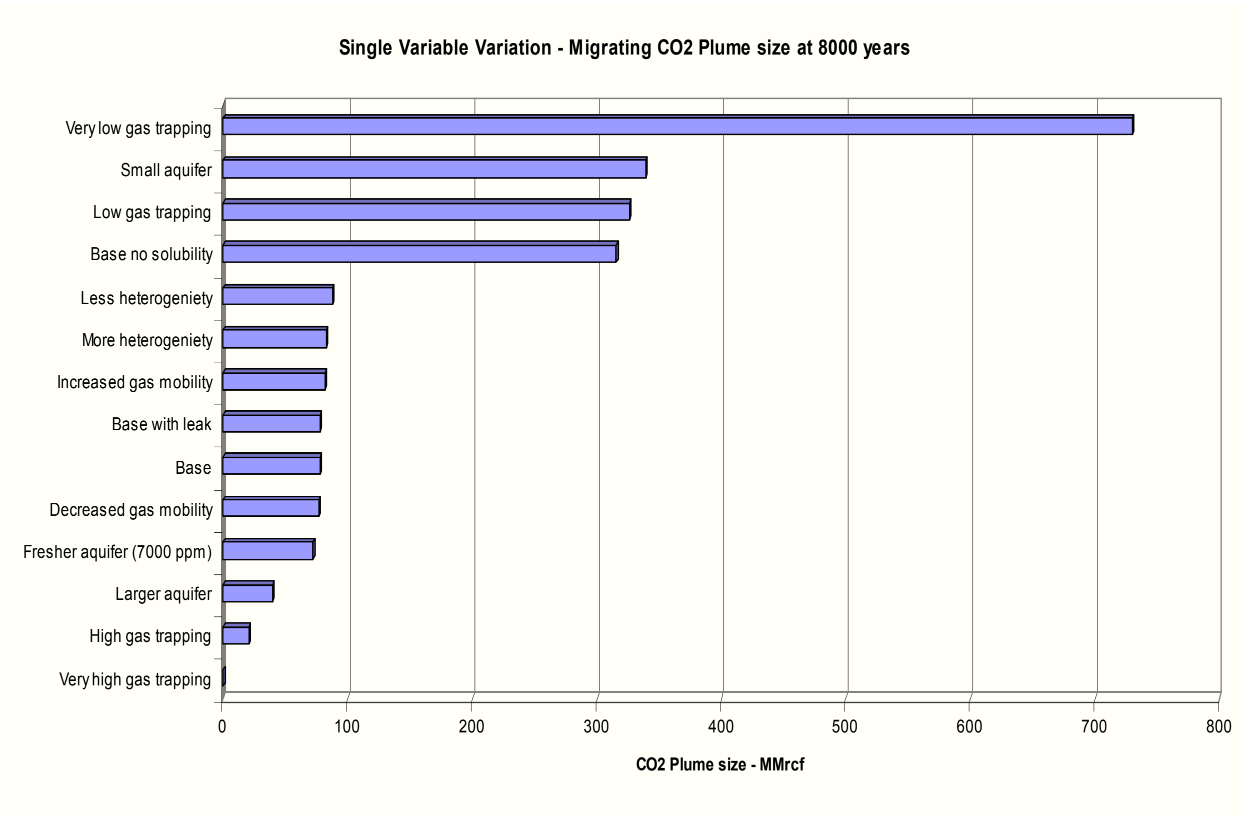

Figure 14: Simple variation; Migrating CO_2 plume size in reservoir at 8000 years.

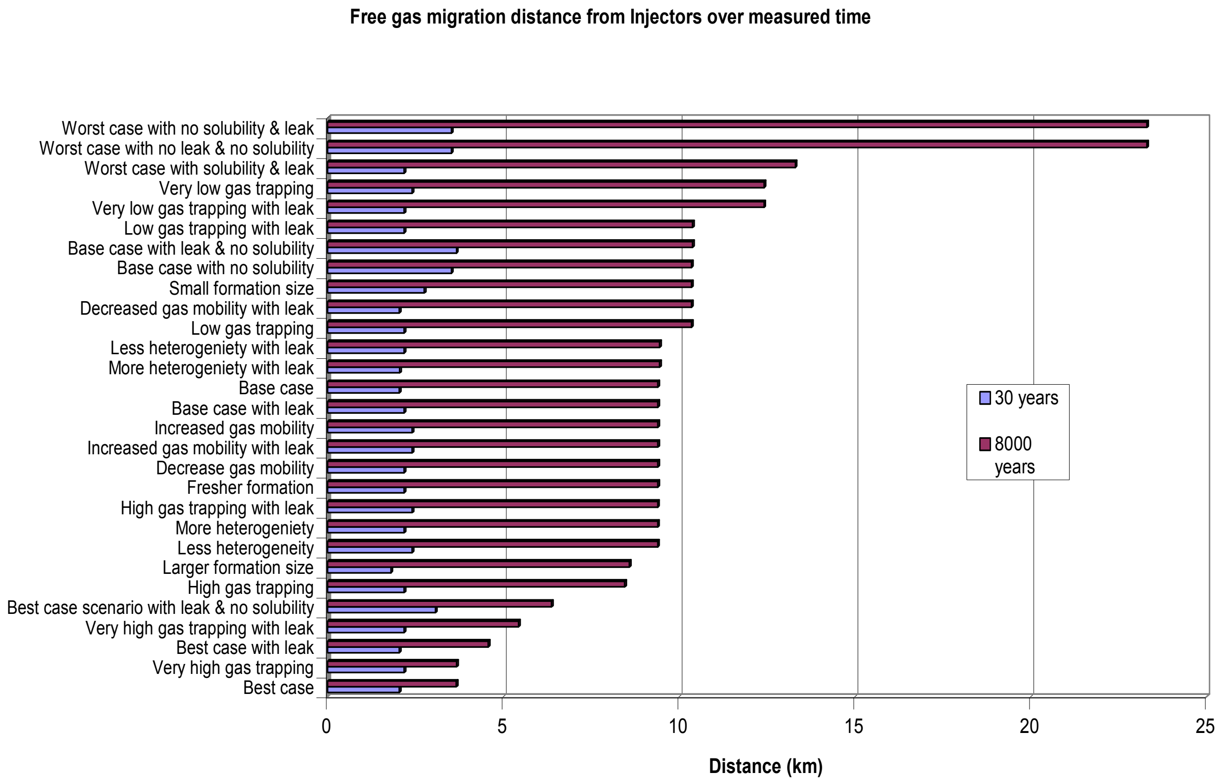

Figure 15: All cases; Free gas migration distance from injectors at 30 & 8000 years

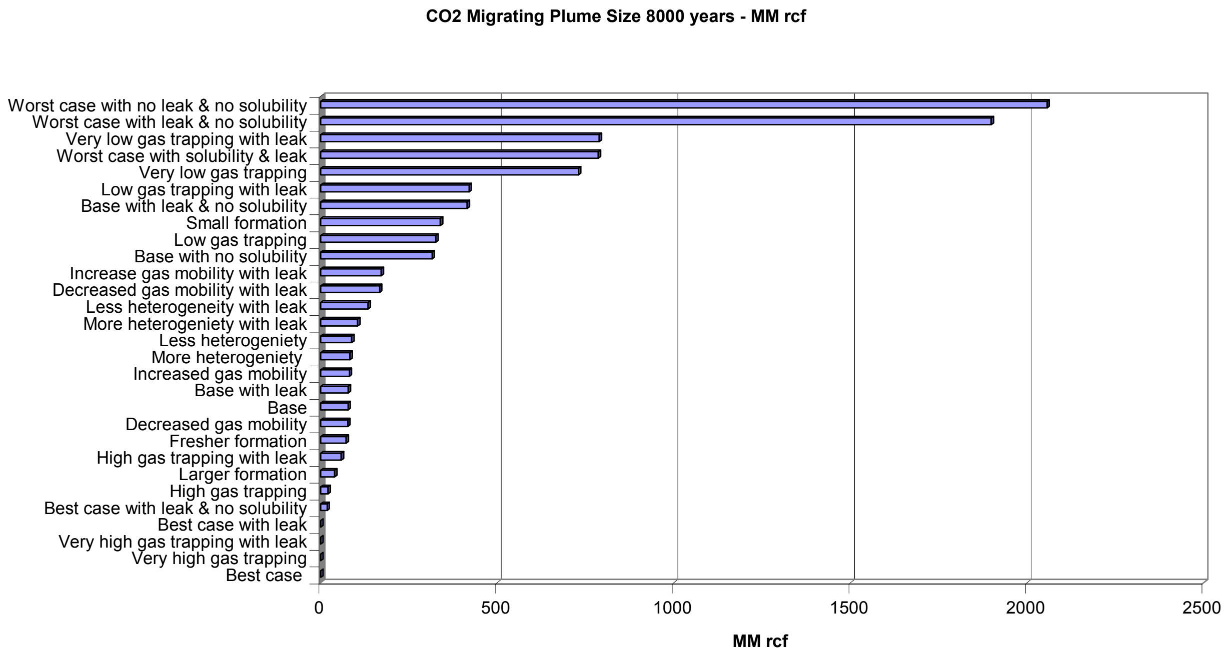

Figure 16: All cases; Migrating CO_2 plume size in reservoir at 8000 years.

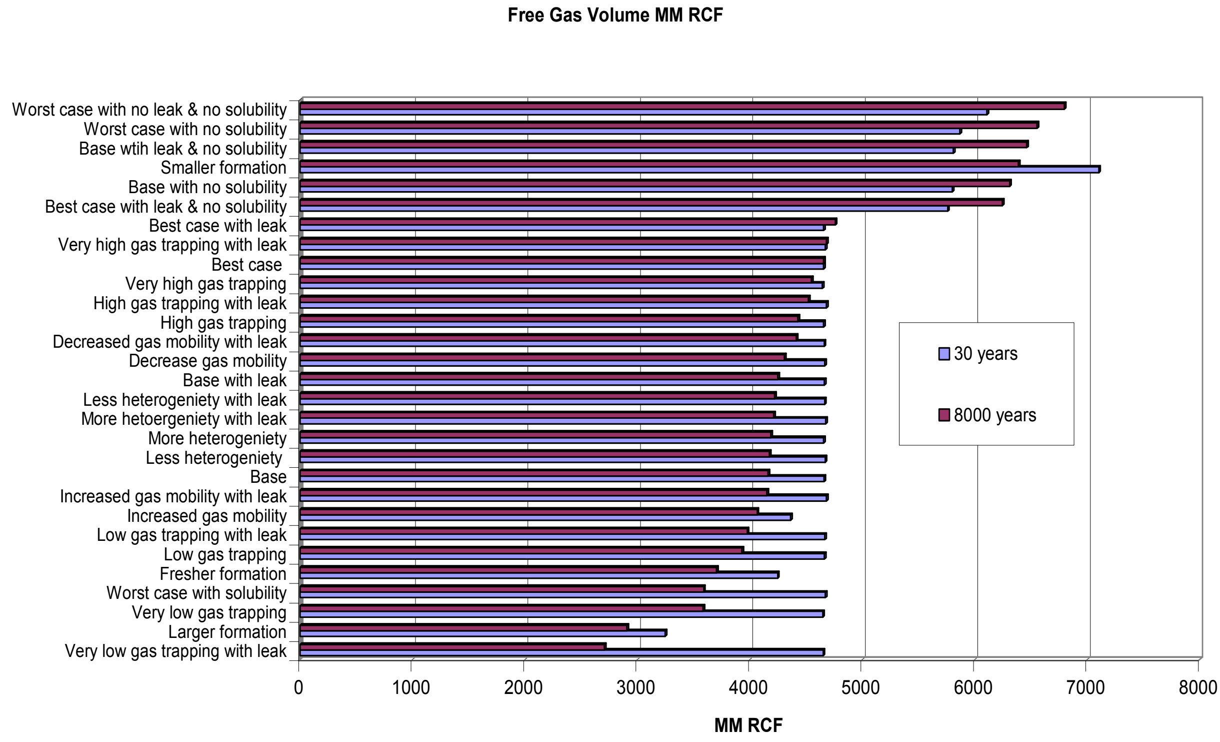

Figure 17: All cases; Free gas volume in reservoir at 30 & 8000 years.

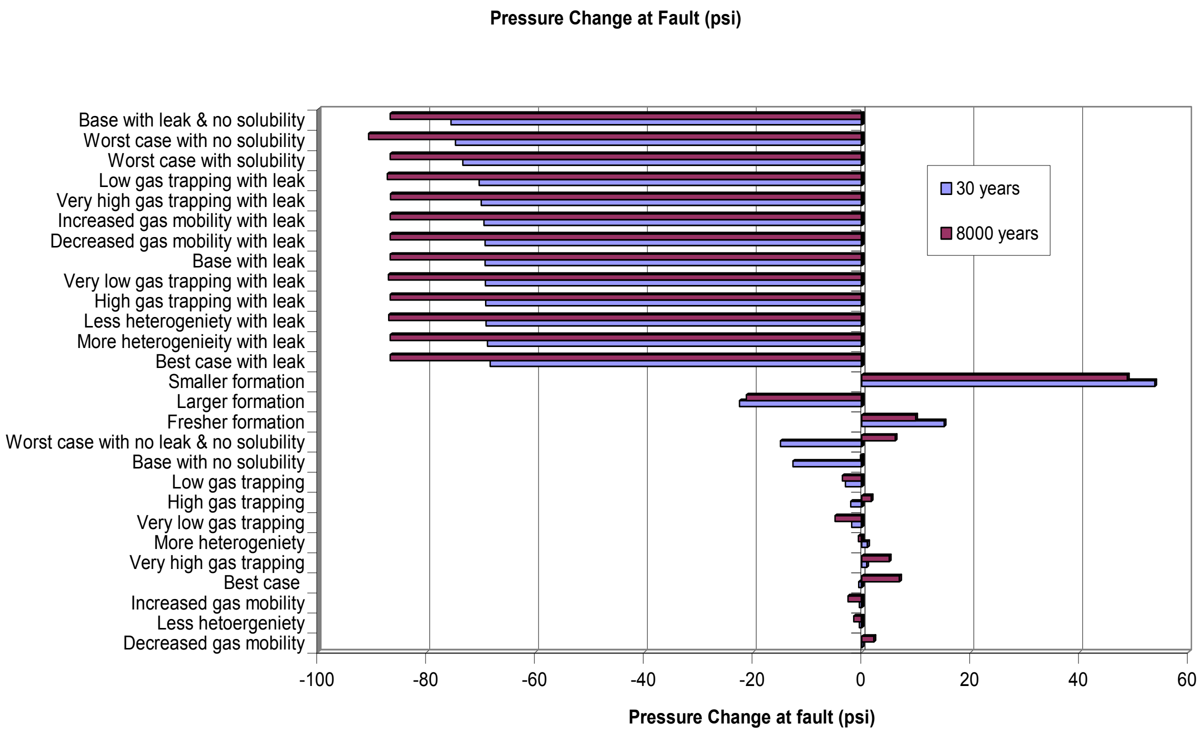

Figure 18: All cases; Pressure change at fault; relative to base case at 30 & 8000 years.